BIOMASS POWER SYSTEMS - WHERE ARE WE, WHERE ARE WE GOING, AND HOW DO WE GET THERE? THE ROLE OF GASIFICATION

Presented at:

EPRI Conference on New Power Generation Technology
October 25-27, 1995
San Francisco, California

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Abstract

The electric power industry, and especially the biomass power industry, in the United States is in a period of great uncertainty. Deregulation, State non-fossil mandates, recent Federal Energy Regulatory Commission (FERC) rulings, expiration of PURPA contracts, potential loss of Energy Policy Act (EPACT) tax credits, and policy changes in the 1995 Farm Bill all contribute to this uncertainty. Simultaneously, many utilities are experiencing pressure to provide waste or residue disposal service for industrial or agricultural customers. The agricultural sector is also anxiously seeking alternative and higher value markets for its products. In this paper, we discuss the current situation in the biomass power industry, some reasons for past industry problems, areas critical for success in the future, a strategy for achieving this success. Results from recent site-specific feasibility studies and other economic and technical analyses are also presented.

Where are we?

In the United States, the period from 1973 to the present has shown a dramatic upswing in bioenergy use, especially in thermal and electrical applications of wood residues. The wood processing and pulp and paper sectors became about 70% self-sufficient in energy in this period, and the amount of grid connected electrical capacity has increased from less than 200 MW_e in 1978 to over 7,500 MW_e today. This dramatic growth, stimulated in part by federal tax policy and state utility regulatory actions, occurred after the Public Utilities Regulatory Policies Act (PURPA) of 1978 guaranteed small electricity producers that utilities would purchase electricity at a price equal to the utilities' avoided cost.

More than 70 % of biomass power is cogenerated with process heat. Wood-fired systems account for 88 %, landfill gas 8 %, agricultural waste 3 %, and anaerobic digestion 1 %. There are nearly 1000 wood-fired plants in the U.S., typically ranging from 10 to 25 MW_e. Only a third of these plants offer electricity for sale. The rest are owned and operated by the paper and wood products industries for their own use. Most of today's biomass grid connected power installations are the smaller scale independent power and cogeneration systems. To date, utilities have been involved in only a handful of dedicated wood-fired plants in the 40 to 50 MW_e size range, and in some co-firing of wood and municipal solid waste in conventional coal-fired plants. Net plant heat rates for 25 MW_e plants in the California PG&E service territory average approximately 20 % efficiency (17,000 Btu/kWh). By comparison the 43 MW_e utility-operated plant at Kettle Falls, Washington, has a reported heat rate of 23.7% efficiency (14,382 Btu/kWh).

The advantageous power purchase agreements that were negotiated under PURPA in the 1980s are no longer available at high avoided cost rates. As a result a number of plants are closing as their power contracts come up for renewal. These plants could be competitive in today's environment using low cost waste and residue fuels if their efficiency was much higher. This has been demonstrated in the Hawaii sugar industry where the sugar mill power plants operate for a major part of the year as combined heat and power (CHP) installations. Investments in efficient steam cycles have resulted in a competitive rate of power generation under PURPA. Low pressure boilers were systematically replaced by higher pressure boiler systems of larger capacity in the period 1960 through 1980, with the average steam pressure and temperature increasing from 1.3 MPa and 210• C to 4.4 MPa and 380• C. Meanwhile, the net steam consumption in the mills decreased significantly from 600 kg /tc (ton of cane) to about 300-400 kg/tc; resulting in a power output of about 60 kWh/tc on average, with the best mills reaching over 100 kWh/tc.

The other significant difficulty faced by the biomass power industry in California has been feedstock cost instability. Figure 1 (1) depicts biomass capacity additions and losses by year, cumulative biomass power capacity, and the fuel cost trend over a fifteen-year period in California. It is clear that, once a market developed, the cost of fuel biomass (largely agricultural waste and residues) more than tripled over a ten-year period. Further, the fuel cost continued to increase, albeit at a lower rate, until biomass power plants began to be bought out and shut down. As with any industry, a reliable feedstock supply available at a predictable price is necessary for the success of a biomass power facility.

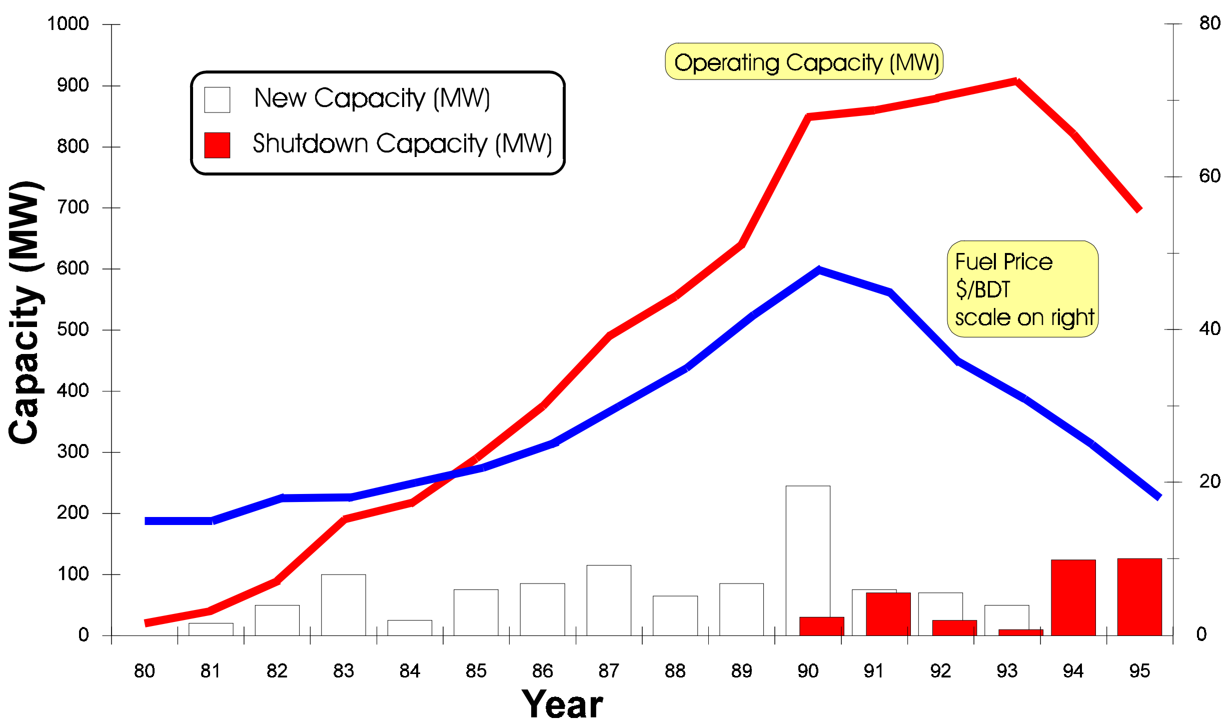

Figure 1. The California Biomass Energy Market

Thus it is clear that not only are biomass power efficiency advances needed to be competitive with low-cost fossil fuels, but an assured supply of reasonably priced feedstock is also necessary. Figure 2 illustrates a planned vs. actual electricity production cost scenario that a producer would face in such a position. The lower bubble displays the cost of electricity that might have resulted in the early 1980s. Contrast this with the significantly increased production cost, and reduced profit, resulting from competition for the feedstock. Also shown is the cost of production from an IGCC system under similar conditions. These calculations assume a load factor of 85% (base loaded), and a return on capital invested of 8% per year. Both plants are approximately 50 MW_e capacity. The efficiency of the steam plant is about 20%, and the advanced IGCC plant is estimated to have an efficiency of 45%. The capital cost of the steam plant is $1800/kW; the IGCC cost is expected to be in the range of $1300 to $1500/kW.

It is also worth noting that the average capacity factor for biomass steam plants recently has been only about 45%. The lower cost of electricity in the IGCC case results from both the increased output (kW) per dollar invested and from the increased system efficiency. As can be seen, the increase in efficiency has two effects: it increases the output (kW) per dollar invested (reduced capital cost), and it reduces the sensitivity of the final cost of electricity to the fuel cost component.

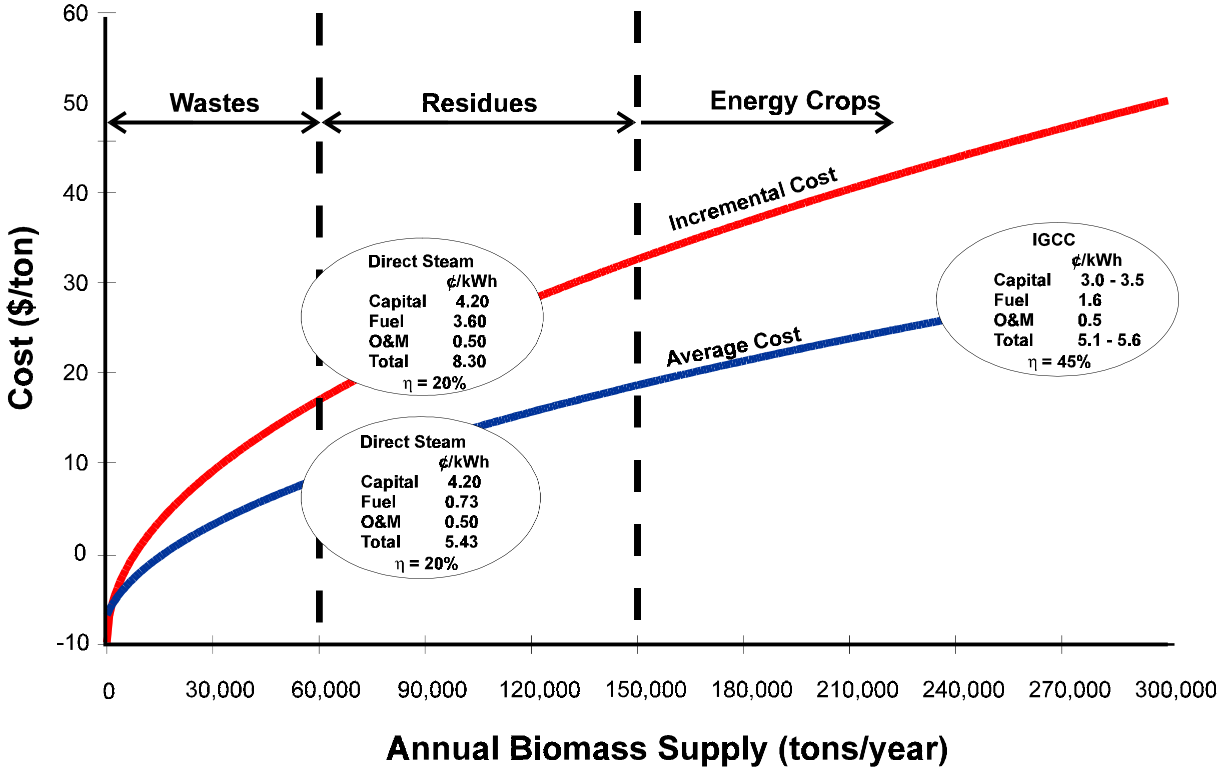

Figure 2. Comparison of present-day steam generation with IGCC

Where are we going?

It became clear in the early 1990s that these two factors, increased system efficiency and reliable and cost-stable feedstocks would be necessary for the stand-alone biomass power market to survive or grow. It was unclear, however, whether the technologies or feedstock supply systems would be available to meet this need. With this in mind, the U.S. Department of Energy (U.S. DOE) Biomass Power program in cooperation with the Electric Power Research Institute (EPRI), Oak Ridge National Laboratory (ORNL), and state energy agencies collaborated in soliciting and funding the site-specific case studies listed in Table 1. These studies resulted in detailed assessments of the potential for biomass power systems and their associated fuel supply systems in economic, environmental, and social settings around the United States. Results from most of these studies have been received and will be published by the U.S. DOE's National Renewable Energy Laboratory (NREL) and EPRI. These studies generated a wealth of valuable data not only relating to the efficiency and cost of conversion systems but also to the viability, sustainability, cost, and environmental benefits of the supply systems. Interest in some areas (e.g. Minnesota) was so strong that biomass producers formed a cooperative with the intent of co-funding the power production facility. Several studies also led to proposals in response to U.S. DOE's request for proposal entitled "Biomass Power for Rural Development."

Table 1. "Economic Development Through Biomass Systems Integration" Feasibility Study Contracts Summary

Contractor	Location	Feedstock	Conversion Technology	Product(s)
PICHTR/ AMFAC	Hawaii	energy cane	gasification/existing boiler	electricity sugar
Chariton Valley RC&D	Iowa	switchgrass, wood residues	gasification/co-firing	electricity
Kansas Electric Utilities	Kansas	sorghum, switchgrass, block locust, silver maple, cottonwood	Fast pyrolysis/combustion turbine	electricity biocrude charcoal
KENETECH Energy Systems	Puerto Rico	sugarcane, energy cane napier grass	direct combustion/steam cycle	electricity sugar
Niagara Mohawk Power Corp.	New York	willow	co-firing	electricity
Northern States Power	Minnesota	alfalfa	co-firing/gasification combined cycle	electricity animal feed
Weyerhauser	North Carolina	pine	gasification combined cycle/ co-gen/ AMOCO ethanol process	electricity ethanol
University of Florida	Florida	elephant grass, sugarcane, eucalyptus, leucaena	combustion/fermentation / SSF ethanol process	ethanol electricity
PICHTR	Hawaii	sugar cane, bagasse, eucalyptus, alfalfa, corn sorghum	AMOCO SSF ethanol process/ gasification/ existing boiler	ethanol electricity animal feed sugar

Wood Industries Co.	California	sorghum, kenaf, poplar, willow, eucalyptus	existing boiler	ethanol, electricity, compost

In the arcane policy analysis literature, all of the economic analyses are performed in terms of the N^{th} plant - this ideal plant represents the ultimate economic performance for that technology. Over the years, a large number of organizations have projected this ultimate performance of biomass-based power systems. These projections, however, often covered a broad cost and performance range that lead inevitably to reluctance on the part of developers to invest in these technologies. In fact, using today's technology for plant #1, the maximum scale that would be risked is probably about 18 MW_e, efficiency in the range 30 - 33%, with a capital investment of >$2500/kW[1]. The only way to resolve these diverse estimates was to obtain estimates done by the hardware developers and engineering firms themselves. This is precisely one of the results from the feasibility studies discussed above.

At about this same time, the Environmental Protection Agency (EPA) embarked on a study to evaluate the penetration of various technologies into the power generation marketplace in the coming decades and their effect on carbon emissions to the atmosphere. This study (3) required as input cost and efficiency estimates for biomass, coal, and natural gas power generation systems. Given the disparity of opinion on these figures in the published literature, a panel consisting of representatives from NREL, EPRI, the Princeton Center for Energy and Environmental Studies, EPA, USDA, and the Colorado School of Mines was convened to arrive at a consensus position. The panel was able to agree upon likely ranges of cost and performance for systems using these fuels. Table 2 summarizes these ranges.

Table 2. Technology characterizations used for EPA modeling.

	Industrial Turbine		**Advanced Turbine Systems**		
Component	Biomass	Coal	Biomass	Coal	Natural Gas
"Low" Technology Specifications					
Heat Rate (Btus/kWh) Efficiency (%, HHV)	8,660 39.4	8,700 39.2	7,579 45.0	7,614 44.8	6,202 55.0
Fixed O+M, $/kW	51.25	51.25	39.66	39.66	28.80
Var. O+M, mils/kWh	3.15	3.15	2.46	2.46	0.712
Total Capital, $/kW	1,230	1,254	1,023	1,047	522.50
"High" Technology Specifications					
Heat Rate (Btus/kWh) Efficiency (%, HHV)	9,400 36.3	8,700 39.2	8,227 41.5	7,614 44.8	6,202 55.0

[1] This by the way is a real example - a biomass IGCC plant in Varnamo Sweden that is currently being commissioned by Bioflow (a consortium of Ahlström in Sweden and the third largest Swedish Utility - Sydkraft)).

Fixed O+M	44.71	36.44	34.60	28.20	28.80
Var. O+M	3.65	2.60	2.85	2.03	0.712
Total Capital	1,488	1,254	1,243	1,047	522.50

Figure 3 correlates all of these studies and cost estimate efforts. The lines on this figure represent 0.8 scale factor curves using, as a base point, the "high" and "low" technology estimates from the EPA study. Plotted as points around the curves are the cost estimates from the various studies shown. The "GEF" study is the Global Environment Fund facility in Brazil that is using TPS gasification technology and a General Electric aero-derivative turbine (3). The other studies are listed in the reference section (3,4,5,6,7).

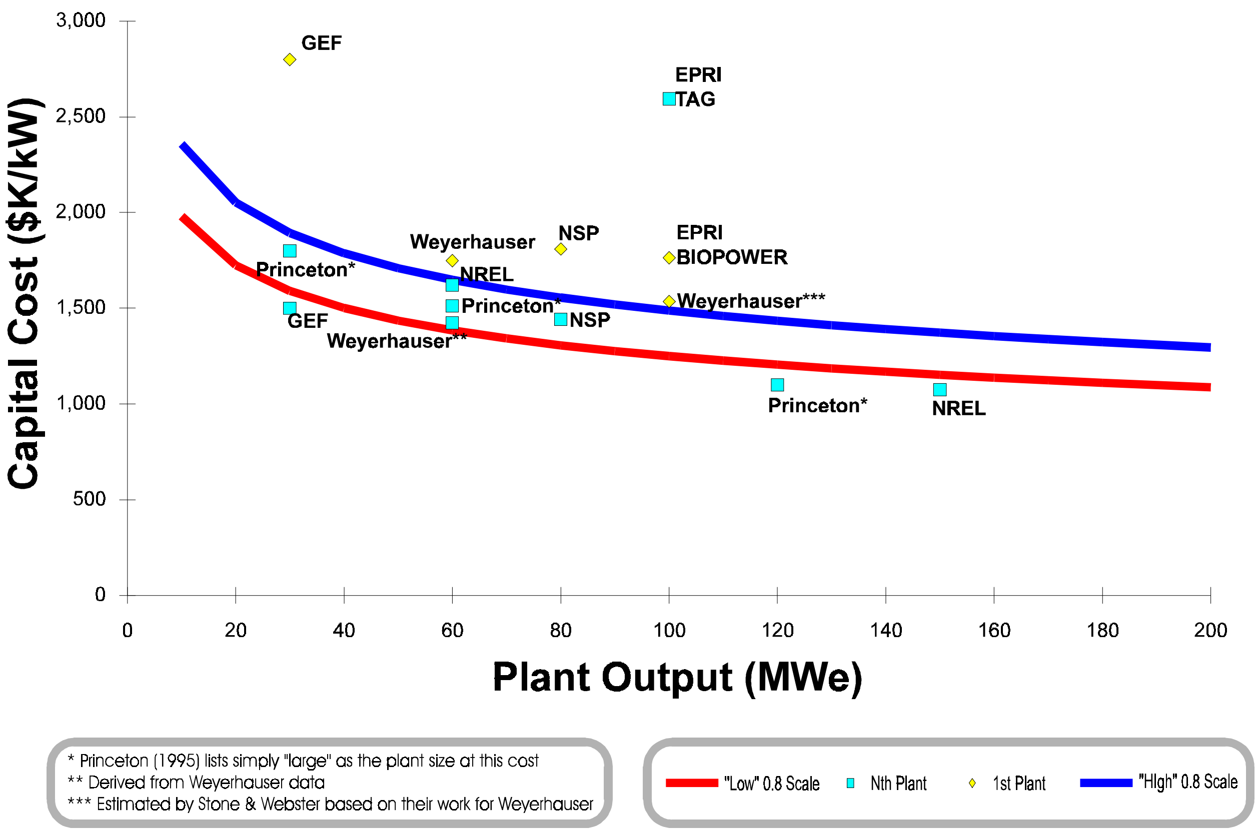

Figure 3. Biomass IGCC Capital Cost Estimates from Several Studies

These studies demonstrate the likelihood that biomass systems' cost and performance can achieve levels that make them competitive or otherwise attractive in existing niche markets. Examples of attractive niches include project with economically attractive co-products (e.g. the NSP study), areas with non-fossil mandates (e.g. Minnesota, the United Kingdom), areas with high fossil fuel costs (Hawaii), areas with rural development concerns (Maine, much of the Midwest), areas with waste or residue disposal concerns (California, the Southeast, British Columbia), and areas with very low biomass costs. It further appears that the number of these niches may be quite large nationally and internationally. The challenge, therefore, is to leverage our collective efforts by: 1) identifying the characteristics of a successful niche and 2) focusing development efforts on technologies that are applicable across numerous niches. In this way, the "summation" across the various niches "equals" a significant market that is ripe for exploitation. To be sure, this market is not the monolithic homogenous one that power producers are familiar with; however, astute and agile developers can position themselves to take advantage of this market domestically and even in the international arena.

How do we get there? - It's too late for linear development!

Given the size of the existing biomass power generation sector, the low and (in some cases) falling prices of fossil fuels, the deregulation of the power generation marketplace, and the pace of development in power generation technologies (gas turbines and fuel cells in particular), we don't have the leisure to engage in the classical development pathway.

It is easy to hypothesize a linear sequence of commercializations starting at a laboratory bench, going to a process development unit (PDU), then to an engineering development unit (EDU), and following this with a pioneer commercial plant and then successive generations of commercial deployment leading to that final N^{th} plant. The sad truth, however, is that the situation is not so deterministic as implied. Worse, in retrospect, it is hard to see such a linear development path for something as complex as a power plant or even an aircraft (even the link between the Wright Brothers and a Boeing 777 cannot be drawn this way).

A better model is to accept that the development sequence continuously "feeds" on progress at a variety of scales in its own and ancillary fields. This is the intuitive reason for the niche opportunity concept. Some critical component can be demonstrated in isolation by setting it into an environment that is not at all experimental. This proves the sub-unit, that is then re-embodying into the main development pathway. Thus, a knowledge interface exists between the engineering and science disciplines involved in scale-up. Through this interface, lessons learned through RD&D and in pioneer plants could be utilized both in future plants and retrofitted into existing plants to improve their performance. This reduces risk and systematically develops investor confidence. Therefore, it becomes clear that it is the management of this knowledge interface that truly determines whether the technology will, in fact, succeed.

It is also true, however, that there are some simple rules of *prudent* scale-up that generally have to be followed. In going from the bench scale to the PDU, a jump of about a factor of 10-20 is often carried out. NREL's ethanol PDU is a case in point - the largest fermenters at the laboratory scale have been of the order of 200 liters - the pilot plant is in the range 1500 to 6000 liters. Sometimes the progressive development of a system is confounded by the fact that some elements do not scale down. An example is particle size in the PDU. It cannot accept chips (5 x 3 x .3 cm in size) because the handling system is too small so some of the components have to be almost full scale and operate at reduced capacity so as to not overwhelm the operation with material. Going from a PDU to an EDU scale is once again factor of 10 - 20 scale-up in the critical subsystem, once again with the constraint that some components may not be commercially available at such a small scale. Gas turbines, for example, are not available in a continuous size range. Rather, in any one manufacturer's line, they are somewhat quantized into power brackets. Thus, critical sizing issues in scale-up can depend on available size ranges.

The different scales: Bench (less than a kg/h); PDU (10 -100 kg/h); EDU (1 - 10 t/h), and the Pioneer (30 - 100 t/h), also have to satisfy different criteria of success. At the bench turning woodchips into ethanol was proven almost 40 years ago for the enzymatic process, and the preliminary economics put together based solely on yield information. At the PDU, issues of reaction kinetics, maximum concentrations of wood, limiting concentrations (because of toxicity) etc., can be established to further refine the economics and develop the design basis for the EDU. It is also worth observing that at the bench scale there may be many different experiments and research groups active over a long period of time because each activity is on the order of only one or two researchers, and small investments are required. Moving to the PDU can commit millions of dollars in investment (e.g. TVA's acid hydrolysis plant cost about $5 million, NREL's PDU about $20 million), and teams of scientists, engineers and technicians (perhaps 5 to 20 in all) have to be committed to round the clock operation. Again, there can be a significant number of PDU facilities operating in parallel, especially when there is commercial competition.

Moving to the EDU scale is an even more difficult decision. The investment can be $25 - 30 million for a small 8 MW_e IGCC (data from PICHTR), to over $70 million for a 20+ MW_e IGCC (data from the World Bank's GEF project in Brazil). The teams are larger both during construction and multi-shift operation because one of the issues to be addressed by an EDU is the long-term stability and operation of key components.

An example of RD&D strategy that links the PDU and EDU scales can be seen for the hot gas cleanup development being followed by NREL and its industrial partners. The PDU stage tested high temperature ceramic filters (the critical technology) at the Renugas® 10 tonne/day PDU in Chicago during a test period of less than 100 hours to establish critical sizing issues. Originally, the optimal filter face velocity for a gas stream contaminated with bagasse ash was not known. Therefore, the number of ceramic filter candles required had to be established by experiment. The PDU hot gas cleanup unit (HGCU) was flexibly designed to accommodate from 2 to 14 candles. Once the sizing data were established, the design of the EDU scale (approximately 8 MW turbine and HGCU facility) could proceed. However, the other critical issue is the lifetime of the ceramic candle materials under the actual conditions of bagasse derived gasification ash. To determine operational lifetimes, the PDU-HGCU will be transferred to the EDU gasifier in Hawaii and operated as a 10% slipstream (it is 100% of the output in Chicago) for at least 1000 or more hours to give the commercial technology developers sufficient confidence to specify these filters in pioneer commercial biomass gasification IGCC plants.

The pioneer plant is normally constructed after sufficient experience has been gained on the EDU and often requires special financing (guarantees of performance may be underwritten by the federal government, or capital cost risk buy-down or subsidized operation may be needed) to ensure early adoption of the technology. Here, real issues of on-stream availability and reliability are addressed as well as showcasing the technology to further its adoption. It should also be recognized that the PDU and the EDU may be maintained in operation while the commercialization is proceeding. The developer can use the plants to prove that novel feedstocks work, or use the PDU or EDU as machines capable of operating in a flexible performance envelope to prove out operation that could be either disruptive or even detrimental to commercial operation. An example of this is the Texaco gasifier for fossil fuels - it is in proven commercial service for heavy oils, recently commercialized for coals, and is being tested on novel mixtures of feedstocks including waste tires and sewage sludge/coal at the EDU and PDU scale.

Learning Curves

Once a technology has reached the stage of the prototype or pioneer plant we expect that a number of improvements will be made *commercially* on an incremental basis. Using the biomass gasifier IGCC concept as an example, we can demonstrate some of the trends that are anticipated to take place. The first unit will be designed and operated in a very conservative fashion (just as the Varnamo unit is being operated, see footnote 1.)   For example, the system specification for the first complete IGCC may have the characteristics of 20 MW_e output; 1650ºF turbine inlet temperature; gas cleaning by means of cooling the gas and quenching prior to an ambient temperature bag-house filter; a heat recovery steam generator at 800 psig pressure; an overall efficiency of 32%, and an installed cost of $2,400/kW. Table 3 shows the anticipated learning curve that proceeds by means of a proposed series of technology improvements. Each succeeding improvement is gained only through increased experience and investment in development. A process of limiting returns does set in as can be seen from the cost of electricity curve in Figure 4. The final stage of improvement would probably come from the U.S. DOE's Advanced Turbine Systems (ATS) program in this instance, and would lead to a system that has 100 MW_e output; a greater than 2300ºF turbine inlet temperature; high temperature gas cleaning; a multiple stage heat recovery steam generator possibly linked as a steam injection unit to the gas turbine; and an overall efficiency of 45%, and an installed cost of approximately $1,000/kW.

Some of the learning curve effect is gained simply by increasing the scale of operation. This is gained through increased confidence in the technology as operators and designers evaluate the systems operation enabling them to undertake such a scale increase without increasing the risk of failure. Typically if a power unit is scaled up by a factor of 2, the price does not double in going from say 50 MW to 100 MW, rather the price of an installed kW may go down from $1,400/kW at 50 MW (for a total of $70 M) to a total cost of $114 M at 100 MW, or an installed cost of $1,140/kW. The reason for this is that the capital investment is scaled with an exponent of approximately 0.7 so that doubling the size does not double the cost but rather increases it only by a factor of 1.62[2].

Crops

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[2] These rules are derived from the relationship of the volume of a sphere to its surface area. That is if the throughput of a plant is to be increased by a factor of 10, then the investment is only increased by about a factor of 0.7 because the investment in metal for the pressure vessels and other containers does not increase directly with the vessel's volume but with the surface area of the container.

Biomass crop development is still very young compared with that of food crops that are grown today. The RD&D necessary to establish the proof of concept of the crops has been undertaken for primarily two crop species in the mainland US: a short rotation woody crop (SRWC) species, hybrid poplar, and a herbaceous energy crop (HEC) species, switchgrass. In Hawaii, the crops that have been partly developed are eucalyptus and leucaena for SRWC, and sugar cane, energy cane, and banagrass for HEC. In the European Union there are also SRWCs and HECs under development with an emphasis on willow (in Scandinavia) and miscanthus for the HEC.

Table 3. Hypothetical series of biomass gasification IGCC developments leading to a learning curve.

Capacity (MW)	TIT (ºF)	Gas Cleaning	Steam Conditions	Efficiency (%,HHV)	Capital Cost ($/kW)
20	1650	Cool+ quench	800 psig	32	2,400
30	1850	Cool + Baghouse	900 psig	34	2,100
50	1900	hot gas cleanup	1250 psig	35	1,900
60	2100	hot gas cleanup	1250 psig	37	1,700
75	2100	hot gas cleanup	1450 psig	38	1,600
100	2200	hot gas cleanup	1450 psig, re-heat	40	1,450
120	2350	hot gas cleanup	1450 psig, re-heat	41	1,350
100	>2300	hot gas cleanup	N/A	45+	>900

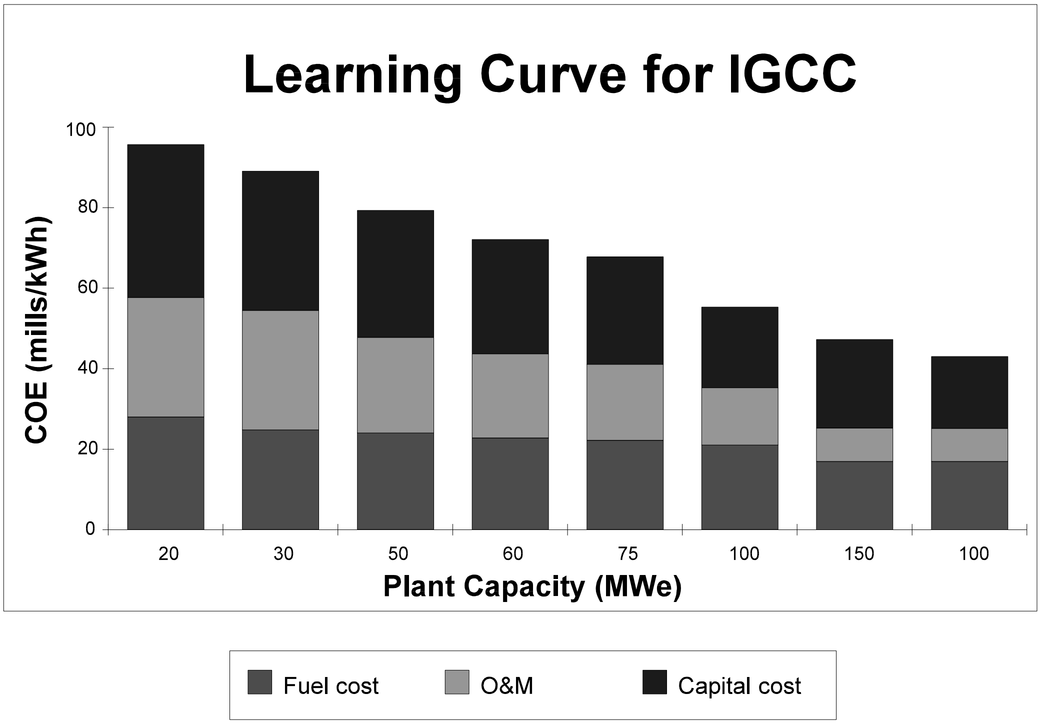

Figure 4. Cost of Electricity Learning Curve(data from Table 3)

In Sweden and Finland the scale of development SRWC for energy has already reached the demonstration stage, while in the U.S., several pulp and paper producing forest companies have taken the early SRWC through demonstration to commercialization for pulp and paper requirements. Although the cost goals per ton of biomass are similar for the two industries, the pulp and paper (P&P) industry has a number of quality constraints that the energy producer would not have. For example the P&P industry requires a very high clean fibre to bark and twigs ratio. It would also like a denser wood to reduce the volume of its digester, and a low amount of color in the fiber to reduce the bleaching and environmental costs. The system they have developed is based on almost a 10-year rotation, with about 30% of the biomass in the form of bark and tops/branches/twigs being used for process energy and the clean fiber being processed within 24 hours of harvest to maintain a uniform product quality. The resulting costs are about $100/t for the produced biomass. The quality goals for energy are somewhat less stringent as to form and for combustion the bark, tops, and stem wood are all suitable, and storage beyond 24 hours does not create any difficulty.

Much of the development emphasis has been placed on the issue of improving the biomass productivity and obtaining the maximum yield as soon as possible as a means of reducing the overall cost of the biomass delivered to the plant. In growing crops such as trees, it is important to have what is called canopy closure as soon as possible. Once the entire planted area is completely covered with the photosynthetic capturing leaves then the site is at maximum capability in capturing the solar energy. This factor increases the costs by demanding close planting to obtain canopy closure early (this also reduces the impact of weed growth) and thus many seedlings to the hectare are needed. With perennials that will regrow from the stump or cut back material (in sugar/energy cane - this is called ratooning, for hardwood trees including poplar, willow and eucalyptus, they will re-sprout from the stump by coppicing, grasses regrow) the establishment costs are incurred only at the beginning and many harvests can be undertaken with grasses and several rotations with trees before the rootstock has to be replaced. Planting can be automated and tending and maintenance are costs that are very necessary in the early years of establishment when the roots of the plants are shallow to ensure their success and avoid stress due to water shortage or competition from weeds.

Harvesting is one area in which there has not been extensive development. For HEC it has been assumed that the current forage harvesters and equipment will be adequate. For SRWC, if the individual stem is close to the size of regular forest harvesting equipment (which it is in the case of the forest industry SRWC for P&P), existing forestry machinery can be used. For crops such as willow that are planted at high density and harvested at about 4 years when there are many stems, special equipment is required. Some of this has been developed in Scandinavia and the European Union, and could be usefully transferred to North America to accelerate the SRWC development.

Current analysis of the costs for crop production shows the following:

> The largest proportion of costs are for harvesting, handling, storing, and transporting biomass (• 40% of total costs). Most of the machinery costs, both operating and capital, and labor costs are for these operations. In the Midwest, land costs are the second-largest expense, accounting for between 15% and 25% of total costs. In the Southeast, because of much lower land rents, land accounts for between 6% and 12% of total costs. For switchgrass and energy cane, fertilizers and weed control account for • 15% of total costs. In the case of hybrid poplar, fertilizers and pesticides account for 7 to 8% of total costs. For energy cane, in 1989, establishment is a major component of cost, • 20% of total costs. By 2010 this will have fallen to only 7% of total costs, because of an assumed longer stand life and mechanization of planting. For switchgrass, establishment costs are only 5 to 7% of total costs. For hybrid poplar, establishment costs are 7 to 8% of total costs (8).

Thus, the most effort needs to be applied to reducing the harvesting, handling, storage and transporting biomass costs. Although no learning curve can be presented for harvesting, corn crop yield in the U.S. has increased at approximately 1.5%/year for the last 50 years. Similar learning curves for crop yield can be anticipated for energy crops, with significant early gains available because the crops proposed have not been developed extensively.[3]

U.S. DOE Biomass Power Program

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[3] The James River Corporation in Oregon more than 8,000 hectares of hybrid poplar planted on river bottom lands. Although they anticipated coppicing and thereby reducing their costs of establishment, the yield improvement actually has been at a rate of greater than 5% per year. Therefore, it has proved to be economically better to replace their 10-year old poplar cultivars with the new improved hybrids at the first harvest (personal communication from Don Rice, Plantation superintendent)

The U.S. DOE Biomass Power Program is working to address the issues of making biomass competitive by working with today's industry to increase its reliability and to develop advanced systems for increased efficiency and environmental performance. The pathways under discussion are included in Figure 5.

Support for Today's Industry

In general, the biomass power industry has displayed good reliability; however, in the case of the independent power producer (IPP) biomass-fueled stations in California, operational difficulties rapidly emerged when using non-wood biomass fuels (9). The operational difficulties were caused by the deposition of mineral matter on heat exchange surfaces (boiler tubes, superheaters, and water walls) and by the agglomeration of ash and inert fluid bed materials. This problem is one that is costly as it results in down-time for tube cleaning and repair. Because there is considerable interest in the development of dedicated crops such as short rotation woody crops and herbaceous energy crops for bioenergy applications, it could be a problem that would affect the long-term large-scale deployment of biomass fuels in both electricity generation and the production of liquid fuels. For this reason the U.S. DOE, through NREL, initiated a collaborative study with industry on the ash deposition problem[4] to establish the root cause of the difficulties in using non-traditional biomass fuels.

[4] Alkali Deposits found in biomass power plants: a preliminary investigation of their extent and nature. NREL Subcontract TZ-2-1-11226-1. Principal Investigator: Thomas R. Miles of Thomas R. Miles Consulting Design Engineers. Participants: Delano Energy Company Inc.; Electric Power Research Institute; Elkraft Power Company (Denmark); Foster Wheeler Energy Corporation; Hydra Co Operations Inc.; Mendota Biomass Power; Inc.; National Wood Energy Association; Sithe Energies, Inc.; Thermo Electron Energy Systems; Wheelabrator Environmental Systems Inc.; Woodland Biomass Power Ltd.; Western Area Power Authority; Sandia National Laboratories; Hazen Research Inc.; Al Duzy and Associates; University of California Davis; U.S. Dept. of the Interior, Bureau of Mines; Appel Consultants, Inc.

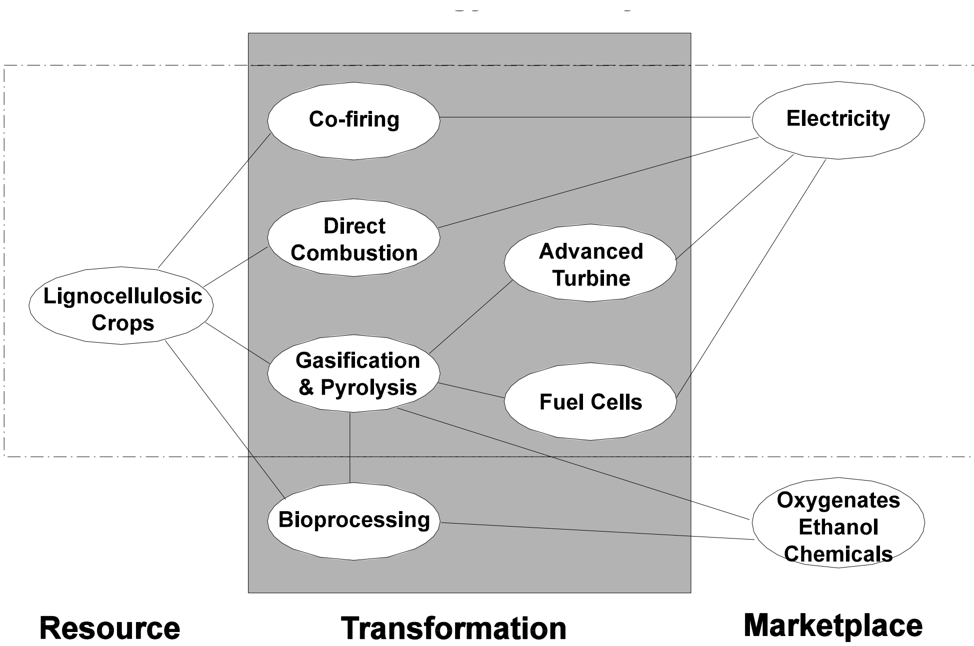

Figure 5. Biomass Energy Pathways

While the nature of the direct combustion boiler problem is of current concern, NREL also recognized that these same issues may have to be addressed in non-combustion processes such as fast pyrolysis and gasification that convert biomass into intermediate fuels for use in very high efficiency generation systems based on gas turbines. Gas turbines are extremely sensitive to both mineral matter and alkali metals. For the state-of-the-art turbines with turbine inlet temperatures of 1260• C (2300• F) the manufacturer's specifications call for less than 300 ppb of alkali metal in the hot section. Because high efficiency biomass-to-electricity conversion is a goal of the U.S. DOE Biomass Power Program[5] a program of testing non-woody and short rotation biomass feedstocks in gasifiers and fast pyrolysis processes was instituted.

The ash deposition problem was addressed by conducting extensive fuels and deposits analysis, and through an extensive collaboration the cause was identified. The project received over 700 different fuels analyses from the participants; however, the majority of these did not have the critical ash analysis data. This may not have been such a bad omission since the project established that there are major problems with the standard ash determination methods that are accepted as standards for coal materials. The ASTM methods for coal prepare an ash at 800• C which is then used for the pyrometric cone analysis to determine if there will be slagging or stickiness problems. Unfortunately, the critical element causing the ash deposition and fouling problem is potassium, and it is known that this and other mineral matter from biomass will evaporate from the ash at 800• C, decreasing its mass and altering its fusion properties (10). Potassium is a key component of cellular function and in plants it can be present at 1000 times

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[5] Electricity from Biomass National Biomass Power Program Five-Year Plan (FY1994-FY1998). Solar Thermal and Biomass Power Division, Office of Solar Energy Conversion, U.S. Department of Energy, Washington, D.C. Draft April 1994.

the concentration of sodium. As much as 35% of the ash in annual plants can be alkali, which drastically reduces the ash fusion temperature from greater than 1300• C in the case of wood ash to about 700• C. At this temperature the potassium can form a eutectic with the plant's silica or the sand medium of the fluidized bed (11). Work with the molecular beam mass spectrometer (MBMS) system at NREL has shown that the form in which potassium is transported can be very diverse including oxides, hydroxide, sulphite, sulfate, and chlorides as volatiles(12).

Gasification Developments

Commercial biomass gasifiers are already in use to generate process heat and steam. Current development activities are focused on producing electricity and, to some extent, liquid fuels, and involve integrating gasification with various cleanup systems to ensure a high-quality and reliable gas product. At this time, there is no clear preference for a single gasifier system. The Global Environment Facility (Elliott, 1993), is evaluating two systems offered by Scandinavian commercial developers for the CHESF project in northeast Brazil. The evaluation has compared the advantages and disadvantages of using air gasification at high pressure (Bioflow) or at low pressure (the TPS system). High-pressure gasification would have to meet the pressure requirements of the chosen turbine on all system components, including the gas clean-up system; the low-pressure system would carry out the gas cleaning before compressing the fuel gas to the turbine operating pressure. Air blown systems produce only a low-heating value gas (less than 5-6 MJ/Nm^3, 150 Btu/ft^3), and a significant loss in efficiency is imposed if the gas must be cooled to ambient temperatures prior to being compressed. For this reason, the American and Scandinavian gasification programs are emphasizing the use of hot gas clean-up systems for the air-blown, low-heating-value gasifiers that will be operated at pressure. Despite this, the TPS system with cold gas cleanup has been selected for the pioneer plant for the reliability reasons discussed in the “Leaning Curve” section above.

The U.S. program has a dual-pathway strategy involving both low- and medium-heating-value gas production. One high-pressure system is capable of generating either low- or medium-heating-value gases according to whether it is an air- or oxygen-blown variant, as is the Renugas® system developed by IGT. The low-pressure strategy in the U.S. is based around two developers of medium-heating-value gas systems who do not use oxygen, but rather use indirect gasification to produce gases having heating values of 15 - 20 MJ/Nm^3 (350-450 Btu/ft^3). Cooling and quenching the gas does not incur a significant efficiency penalty, and compared with low-heating-value gas, there are essentially no modifications required in the turbine combustors to handle the medium-heating-value gas fuels.

The Pacific International Center for High Technology Research (PICHTR) Project (>6 MW$_e$)

The U.S. DOE and the state of Hawaii have joined with PICHTR in a cost-shared cooperative project to scale up the Institute of Gas Technology (IGT) Renugas® pressurized air/oxygen gasifier to a 40-82 tonne/day engineering development unit (EDU) operating at 1-2 MPa using bagasse and wood as feed. The site is the HC&S sugar mill at Paia, Maui, Hawaii; NREL is providing project oversight in addition to systems analysis. The first phase, which is now being commissioned consists of the design, construction, and preliminary operation of the gasifier to generate hot, unprocessed gas. The gasifier is designed to operate with either air or oxygen at pressures up to 2.2 MPa, at typical operating temperatures of 850• -900• C. In Phase 1, the gasifier will be operated for about four months at a feed rate of 40 tonne/day at a maximum pressure of 1 MPa. Following the end of Phase 1 in late 1995, a hot-gas cleanup unit and gas turbine will be added to the system to generate 3–5 MW_e of electricity.

The Vermont Gasifier Project with FERCO and the McNeil Generating Station (>15 MWe)

Future Energy Resources Company (FERCO) of Atlanta, Georgia, is the licensee of the Battelle indirect gasification system, and the scale up is at the site of the Burlington Electric Department's McNeil station in Burlington, Vermont. The project, which is in two phases, will first take feedstock from the 50 MW_e station and after gasification will return the gas to the boiler. The scale of operation is about 200 tonne/day. The second phase will incorporate approximately 15 MW_e of turbine electricity generation. The project is jointly funded by U.S. DOE and FERCO and presently construction is forecast to start in Fall 1995.

National Renewable Energy Laboratory (NREL) Activities

The research strategy is guided by systems analysis and technoeconomic assessments of gasifier-based power cycles. In the laboratory, research is ongoing to develop catalysts for hot gas conditioning and to use advanced instrumentation and chemometrics for feedstock characterization and evaluation. One element of this research is using advanced mass spectrometry to characterize alkali metal speciation under gasification and combustion of biomass conditions. This work has been extended to develop and using a transportable molecular beam mass spectrometer (TMBMS) for real time measurement of hot stream composition to 500 atomic mass units (amu). The TMBMS is being used by both Battelle and IGT to measure gasifier and catalyst performance in the field.

Conclusion

There appear to be niches wherein biomass power systems are either competitive or desirable. The success of projects targeted at these niches are dependant upon numerous factors, but among the most important of these are a reliable, cost-stable feedstock and reliable advanced technology. The technical barriers and cost uncertainties associated with both of these are steadily falling. To maintain or accelerate the development and deployment pace in the timely fashion required to capture attractive domestic and international markets, it is necessary to pursue a tightly coupled and well integrated development, testing, and demonstration program.   Such a program must incorporate results from all stages and sizes into all others. This will further allow biomass power systems to adequately and effectively leverage the technical developments taking place outside the Biomass Power program in power conversion technologies such as turbines and fuel cells. The aggregate of these factors will permit the industry to rapidly traverse the learning curve to reduce costs and uncertainty and create a vibrant biomass power industry.

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